BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2018-319-E

In re: Application of Duke Energy Carolinas, LLC for Adjustments in Electric Rate Schedules and Tariffs and Request for an Accounting Order

DIRECT TESTIMONY OF
EZRA D. HAUSMAN, PH.D.
FOR SIERRA CLUB
-PUBLIC VERSION-

I. PROFESSIONAL QUALIFICATIONS AND PURPOSE OF TESTIMONY

Q. Please state your name, occupation, and business address.

A. My name is Ezra D. Hausman, Ph.D. I am an independent consultant doing business as Ezra Hausman Consulting, operating from offices at 77 Kaposia Street, Auburndale, Massachusetts 02466.

Q. Are you providing any exhibits with your testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit No.	Marked Confidential by DEC	Description
1	No	Resume of Ezra D. Hausman, Ph.D.
2	No	Response to Sierra Club Data Request 1-3
3	No	Response to Sierra Club Data Request 1-5
4	No	Response to Sierra Club Data Request 1-7
5	No	Response to Sierra Club Data Request 1-9
6	Yes	Response to Sierra Club Data Request 2-1
7	Yes	Response to Sierra Club Data Request 1-16
8	Yes	Response to Sierra Club Data Request 1-2(a), attachment 1
9	Yes	Response to Sierra Club Data Request 1-2(a), attachment 3
10	Yes	Response to Sierra Club Data Request 1-2(b)
11	Yes	Response to Sierra Club Data Request 1-2(a), attachment 2
12	Yes	Response to Sierra Club Data Request 1-2(a), attachment 4
13	Yes	Response to Sierra Club Data Request 1-13

Q. What is your educational and professional background?

A. I hold a BA in Psychology from Wesleyan University, an MS in Environmental Engineering from Tufts University, an SM in Applied Physics from Harvard University, and a Ph.D. in Atmospheric Chemistry from Harvard University. I have been involved in analysis of both regulated and restructured electricity markets for over 20 years.

I have worked as an independent consultant and expert based on my expertise and experience in energy economics and environmental science since 2014. From 2005 until early 2014, I was employed at Synapse Energy Economics, Inc., a research and consulting company located in Cambridge, Massachusetts, where I served most recently as Vice President and Chief Operating Officer. At Synapse, and continuing as an independent consultant, I have provided expert consulting services in areas including: state and regional energy, capacity, and transmission planning, including both utility resource planning and long-term (multi-decadal) climate-constrained resource planning; regulatory and ratemaking proceedings; electricity and generating capacity market design and analysis; energy efficiency programs; electric system dispatch modeling; economic analysis of environmental and other regulations, including greenhouse gas regulation, in electricity markets; economic analysis, price forecasting, and asset valuation in electricity markets; quantification of the economic and environmental benefits of displaced emissions; treatment of energy efficiency and renewable energy in electricity and capacity markets; and regulation and mitigation of greenhouse gas emissions from the supply and demand sides of the U.S. electricity sector.

Prior to joining Synapse, I was employed from 1998 through 2004 as a Senior Associate at Tabors Caramanis and Associates (TCA) of Cambridge, Massachusetts. In 2004, TCA was acquired by Charles River Associates (CRA), where I remained until I joined Synapse in 2005. At TCA/CRA, I performed a wide range of electricity market and economic analyses and price forecast modeling studies. These included asset valuation studies, market transition cost/benefit studies, market power analyses, and litigation support. I have extensive personal experience with market simulation, production cost modeling, and resource planning methodologies and software.

I have provided testimony and/or appeared before public utility commissions or legislative committees in Arizona, Florida, Illinois, Idaho, Iowa, Kansas, Louisiana, Maryland, Massachusetts, Minnesota, Mississippi, Missouri, North Carolina, New Hampshire, New Jersey, Nevada, South Dakota, Vermont, Virginia, and Washington State, as well as at the federal level. My clients have included numerous State agencies, the federal Department of Justice and the Environmental Protection agency, non-governmental organizations, industry associations, resource developers, and others. I have provided expert representation for stakeholders at the PJM ISO, the California ISO, the Midwest ISO, and at the FERC.

I have provided a detailed resume as Exhibit 1.

Q. Have you previously testified before the South Carolina Public Service Commission?

A. No.

Q. What is the purpose of your testimony in this proceeding?

A. In my testimony, I review the costs and risks associated with continued operation of DEC's Allen, Belews Creek, Cliffside, and Marshall plants, and I caution against the continued investment in coal units that are likely to be uneconomic for customers.

Q. What are your recommendations for the Commission in this proceeding?

A. I recommend that the Public Service Commission of South Carolina ("Commission") require DEC to complete a comprehensive economic and retirement analysis of each of its coal units. This analysis should identify and quantify the total costs of managing past and future coal combustion residuals ("CCR") as well as the costs of all future capital investments necessary to continue operating the plants, including additional investments to manage coal ash and other environmental compliance requirements. This comprehensive analysis should include full consideration of non-fossil-generation alternatives for meeting customer requirements, including transmission enhancements, renewable energy sources, energy efficiency, and storage. If the Commission otherwise concludes that DEC's request for recovery of coal ash remediation and cleanup costs in this proceeding are reasonable and prudent, the Commission should condition its approval on the Company's filing this comprehensive analysis for Commission review. This will allow the Commission to consider whether DEC's coal ash remediation investments provide commensurate benefits to ratepayers in the full context of the past and future operations of DEC's coal units.

Further, once the costs, benefits, and customer risks associated with continued operation of the plants versus all viable alternatives are fully evaluated, the Commission will be better positioned to assess the reasonableness and prudence of any proposed additional capital investments. Such a comprehensive evaluation will also allow the Company to better plan for transitioning to a cleaner energy mix, while minimizing the impact on ratepayers.

II. Costs Associated with Coal Combustion

Q. Is DEC seeking recovery of costs associated with the management and storage of coal combustion residuals?

A. Yes. DEC is seeking "costs associated with compliance with new regulations relating to the management and storage of coal combustion residuals, including fly ash, bottom ash, and flue gas desulfurization byproducts." (Application at 6.) According to DEC witness Kim H. Smith, "The Company proposes to amortize the combined Regulatory Asset of $242 million over 5 years. The annual amortization expense is $48 million. When added together with the net of tax return on the unamortized balance of $14 million, the total revenue requirement requested in this case for deferred coal ash related compliance costs is $62 million." (Smith Direct at 23, lines 14-19.)

Q. Are there additional costs that DEC will incur in the future related to cleanup and remediation of its CCR wastes?

A. Yes. DEC "expects to continue to invest significant amounts related to coal ash compliance after the December 2018 cut-off in this case." (Smith Direct at 23, lines 19-21.)

Q. Were these costs included in DEC's application?

A. No. Rather than include those costs in its current rate request DEC "is requesting the Commission approve a continuation of the deferral, similar to what it approved in Docket 2016-196-E, for costs not included in this case. Specifically, the Company is requesting approval to defer CCR compliance spend related to ash basin closure beginning January 1, 2019, the depreciation and return on CCR compliance investments related to continued plant operation placed in service on or after January 1, 2019, and a return on both deferred balances at the overall rate of return approved in this case." (Smith Direct at 23-

24.) In fact, DEC has not even determined the total cost for closure of its ash basins.

Q. Should the Commission be concerned that DEC is not identifying these future cleanup costs in the current case?

A. Yes. These ongoing costs, and DEC's requested return on these costs, are likely to be substantial. Based on the Company's filings with the North Carolina Utilities Commission, closure costs could total more than two billion dollars over forty years.[1] The Commission can expect to see requests for inclusion of these costs in future rate case revenue requirements calculations, despite the fact that these costs arise from long-ago combustion at coal plants that provides no benefit to current and future ratepayers—in fact many or all of these coal plants will be long closed by the time the cleanup is complete.

Costs that are likely to affect ratepayers for decades to come should not be hidden in a piecemeal series of rate requests without a full analysis and disclosure to the Commission—only by identifying the total cost now can the reasonableness of the Company's request be adequately evaluated. The Commission should insist on a comprehensive retirement study that compares the full suite of future environmental and coal ash costs and closure options to the option of accelerating the retirement of the plants and avoiding these costs to the extent possible.

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[1] In re Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges, Direct Testimony of Jon F. Kerin, Exhibit 11 (Aug. 25, 2017), *available at* https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=e862c96d-8254-4244-8017-14d8d7d1bf03.

Q. Is DEC making any additional capital investments in its coal plants related to the handling or disposal of CCR?

A. Yes. Mr. Kerin states that "the Company is adding dry fly ash, bottom ash, and FGD blowdown handling systems to operating coal-fired plants that are not already so equipped." (Kerin Direct at 8, lines 19-21.) It is not clear from this statement the degree to which these investments are included in the current rate request, or are part of the request for deferred accounting, or in general how the Company plans to recover costs for these projects. However, the ratepayer funds involved would seem to merit more than this cursory description.

As provided in response to Sierra Club data requests, as of January 31, 2019 DEC had spent approximately $47 million on dry fly ash handling upgrades (Response to Sierra Club Data Request 1-3, attached as Exhibit 2); $224 million on dry bottom ash handling (Response to Sierra Club Data Request 1-5, attached as Exhibit 3); $88 million on FGD blowdown handling (Response to Sierra Club Data Request 1-7, attached as Exhibit 4); and $52 million on wastewater treatment at Cliffside (Response to Sierra Club Data Request 1-9, attached as Exhibit 5). This is a total of approximately $411 million in capital investments that were made not to remediate the ash ponds, but to keep the coal plants running under the updated ash handling mandates.

Q. Are the full costs of managing DEC's existing and future ash waste and impoundments, including capital additions to its plants, known at this time?

A. No. The closure of coal ash basins and cleanup of groundwater contamination, which involves such complicated variables as underground soil properties and groundwater flow, are subject to even greater uncertainties. Further, the Company's assertion that cap-in-place at the Allen and Marshall impoundments will adequately achieve long-term protection of and cessation of discharges to ground and surface waters is uncertain. The North Carolina Department of Environmental Quality has yet to approve DEC's basin closure plans. In South Carolina and Virginia, utilities have been required to excavate their coal ash basins. Thus, excavation could ultimately be required for DEC’s ash basins, at significantly greater cost, in order to fully protect groundwater and surface water.

Q. Are there additional costs, in addition to those associated with management of combustion residuals, that DEC will incur to keep Allen, Cliffside 5, and Marshall operating between now and the Company’s current retirement projections?

A. Yes. According to Witness Miller’s testimony, DEC “plans to invest approximately $1 billion in its Fossil/Hydro/Solar fleet” just over the next three years. (Miller Direct at 14, lines 5-7.) Planned capital expenditures at the Company’s coal plants, along with expenditures since 2013, are shown in [CONFIDENTIAL] Table 1. The Company should be put on notice that these types of costs will not be approved for recovery from ratepayers in the future unless and until they are shown to be in ratepayers’ interests through a comprehensive retirement analysis, including a full consideration of alternatives.

[CONFIDENTIAL] *Table 1. Recent and Planned Capital Expenditures at DEC Coal Plants*

[redacted]

Q. Please briefly describe the kind of comprehensive retirement analysis you recommend.

A. DEC should be directed to perform a comprehensive retirement analysis of its coal plants, considering a range of future market conditions, such as fuel costs, emissions costs, and regulatory drivers. The analysis should take into account uncertainty in future operating and CCR management costs. It should consider partial shutdown options as well as full plant retirements. Importantly, the analysis should include consideration of a full range of alternatives for meeting customer needs in the absence of each coal unit, including demand management, transmission, renewables, and storage, to determine the extent to which future costs and risks can be reduced by early retirement of any or all of the units at the Company's coal plants in favor of non-fossil energy solutions.

Q. Has DEC performed any retirement analysis for its currently operating coal plants, and if so, what did it find?

A. [CONFIDENTIAL] [redacted]

[redacted]

[redacted] [CONFIDENTIAL]

Q. Has the Company met the standard you have described for a "comprehensive retirement analysis"?

A. [CONFIDENTIAL] [redacted] [CONFIDENTIAL]

Other utilities have performed comprehensive analyses, considering a range of resources such as demand-side resources, transmission solutions, renewable energy, and storage, and have found that these alternatives can be competitive or even superior at reducing cost and risk.

Q. Can you provide any examples?

A. Yes. One example can be found in the Northern Indiana Power Supply Company's

("NIPSCO") 2018 IRP, for which the Company's capacity expansion modeling showed that retiring all of its coal units early was the lowest-cost option for ratepayers. Under its "preferred plan", NIPSCO proposed to accelerate the retirement of 85% of its coal capacity by the end of 2023 and 100% by the end of 2028, and "[r]eplace retired coal generation resources with lower cost renewables including wind, solar and battery storage."[2]

In a 2017 utility rate case, the Michigan Public Service Commission directed Consumers Energy to file a retirement study for a number of its coal units as part of its upcoming IRP, and to do so expeditiously while certain capital costs at these units could still be avoided.[3] When Consumers did this analysis, it concluded that retiring two of its four coal units in 2023 (instead of 2031, the end of their design lives) was the preferable option for ratepayers, especially when the uncertainty over future costs was considered.[4] According to Consumers witness Thomas P. Clark, the Company's "Preferred Course of Action" ("PCA") "includes increasing [energy waste reduction] from current levels to 2.25%, ramping DR resources to 1,250 MW, implementing Conservation Voltage Reduction ("CVR") with the enablement of the Company's Grid Modernization initiative, and constructing up to 5,000 MW of new solar generation resources by 2031. Additional solar

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[2] Northern Indiana Public Service Company LLC, 2018 Integrated Resource Plan 3 (Oct. 31, 2018), *available at* https://www.nipsco.com/docs/default-source/default-document-library/2018-nipsco-irp.pdf.

[3] In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief; Case No. U-18322, March 29, 2018 Order, *available at* https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000002283XAAQ.

[4] In re the application of Consumers Energy Company for approval of its integrated resource plan, before the Michigan Public Service Commission, Case No. U-20165, Application at 2, 8-9, 32 (June 15, 2018), *available at* https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000231usAAA.

and battery storage is planned to meet load growth and backfill plant retirements throughout the 2030's resulting in 450 MW of battery storage and an incremental 1,350 MW of solar."[5] Mr. Clark further stressed that "The PCA does not incorporate a new NGCT nor NGCC to meet any of the Company's projected capacity needs. The PCA includes incremental levels of demand-side management and renewable generation."[6]

Q. Has DEC adequately justified its decision to continue running all of its coal units until the probable retirement dates identified in the 2016 depreciation study?

A. No. According to DEC's responses to Sierra Club data requests [CONFIDENTIAL] [redacted]

[5] In re the application of Consumers Energy Company for approval of its integrated resource plan, before the Michigan Public Service Commission, Case No. U-20165, Direct Testimony of Thomas P. Clark, 6-7 (June 15, 2018) *available at* https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000231usAAA.

[6] Ibid, page 64.

[redacted] [CONFIDENTIAL]

III. Remaining Life of the Allen, Cliffside, and Marshall Coal Plants

Q. What are the expected retirement dates of DEC's Allen, Cliffside, and Marshall plants?

A. As shown in the direct testimony of DEC witness David L. Doss, Jr., Exhibit 2 (2016 Depreciation Study), the Allen plant has a "Probable Retirement Year" of 2026; Cliffside Unit 5 of 2032; and Marshall of 2034. By those dates, the Allen and Marshall plants will have been in service for 69 years and Cliffside Unit 5 for 60 years. The Company is required by court order to retire Allen Units 1, 2, and 3 in December 2024.

Q. What was the basis of DEC's projected end-of-life dates?

A. As described on page III-6 of the 2016 Depreciation Study (Doss Exhibit 2), "The depreciable life span estimates for power generating stations were the result of considering experienced life spans of similar generating units, the age of surviving units, general operating characteristics of the units, major refurbishments, discussions with management personnel concerning the probable long-term outlook for the units, and the estimate of the operating partner, if applicable…the depreciable life span estimate for most steam, base-load units is 36 to 69 years, which is within the typical range of life spans for such units."

Q. Have the assumed retirement dates for these units changed since the Company's last depreciation study?

A. Yes. The expected remaining lifetimes were reduced for a number of DEC's fossil generating resources, including the Marshall and Allen plants, "to better align with the industry information for supercritical and subcritical coal units and assumptions for future environmental regulations." (Miller Direct at 7, lines 8-9.) Referring to the date of the last unit retirement at each plant, Mr. Miller states that "the probable retirement date for the Allen Station was reduced to 2026; the probable retirement date Cliffside Unit 5 was updated to 2032; . . . and the probable retirement for the Marshall Station was reduced to 2034." (Miller Direct at 7, lines 10-13.)

Q. Are the revised probable retirement dates for Allen, Cliffside 5, and Marshall reasonable given the changes in industry outlook between 2010 and the present?

A. No. these lifetime projections cannot be reconciled with current industry conditions and trends. Absent a unit-specific analysis, I find that the projected retirement dates for Cliffside 5 and Marshall, in particular, do not comport with the challenges facing coal plants and the likely impact on future operations at DEC's coal plants. In fact, the economic and regulatory environment for coal plants today is manifestly different from the conditions in 2012, when the Company's previous depreciation study was completed.

Q. Please explain.

A. Throughout the 20th century and into the first decade of the 21st, there were very few retirements of coal plants, as demand for power grew and the availability and the relatively low cost of coal made it more attractive to utilities than alternative energy sources. In addition, the environmental and public health impacts of coal combustion were less well-known than they are today (or were considered an acceptable cost of this engine of economic growth). In 1970, the US Congress passed the Clean Air Act and began the process of requiring coal plants to install pollution controls to reduce the environmental and health impacts of their emissions. However, Congress exempted many existing coal plants from strict emissions control requirements. This loophole had the unintended consequence of actually prolonging the life of many coal plants that lacked modern pollution controls, as companies sought to avoid the costs associated with the technology that would be required on new, or substantially refurbished, coal-fired power plants.

Since around the time of DEC's last depreciation study in 2008, however, the rate of coal plant retirements or conversions has increased dramatically. In much of the country, the growth in demand for electricity has slowed or even halted due to factors such as stringent appliance energy efficiency standards, along with utility-run energy efficiency programs. More recent environmental regulations have required existing coal-fired plants to reduce their emissions of harmful and haze-inducing pollutants, in addition to better management of their water use, their impact on aquatic life, and disposal of coal combustion residuals. These mandates can necessitate capital investments in equipment upgrades in order for plants to continue operating.

At the same time, the cost of renewable energy sources has plummeted, while the demand for renewable-sourced energy has increased, both because of the sharply decreasing costs of renewable energy and as a result of state Renewable Portfolio Standards and other state and federal policies. The US Department of Energy's Annual Energy Outlook (AEO) for 2019 projects an increase in U.S. renewable generation of 59% over 2017 levels by 2035, compared to a *decrease* in output for coal generation of 22%. As the capability of battery storage increases and the cost declines, the pairing of solar energy and battery storage systems makes high penetrations of solar energy to meet both energy and capacity needs increasingly feasible.[7]

Finally, coal-fired plants are very large emitters of carbon dioxide (CO_2) and other greenhouse gases, which have well-documented and extremely harmful long-term impacts on the Earth's climate and environment, human health, and economic well-being. The United States currently lags other countries in federal policies to address this threat. However, numerous states—for example, the members of the Regional Greenhouse Gas Initiative (RGGI) in the Northeast—are moving aggressively to reduce the greenhouse gas emissions associated with electricity production, and are transforming the regional electricity market by pushing the generation mix away from high-carbon sources and towards cleaner generating technologies. On October 29, 2018, the North Carolina Governor signed an Executive Order setting a statewide goal of reducing greenhouse gas emission to forty percent below 2005 levels by 2025.[8] There has also been widespread recognition throughout the electric industry that the United States will ultimately implement policies that impose a price on greenhouse gas emissions, as the deleterious effects of global climate change become increasingly difficult to ignore or deny.

These factors have led to conditions where many coal plants cannot compete

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[7] See, for example, "Solar+Storage: Reducing Barriers through Cost-optimization and Market Characterization, a joint endeavor of Clean Energy Group and the National Renewable Energy Laboratory (NREL)" and othe related reports at https://www.cleanegroup.org/ceg-projects/solar-storage-optimization/.

[8] https://www.newsobserver.com/news/politics-government/state-politics/article220789175.html.

economically, and even more cannot justify continued investments in either environmental upgrades or other significant capital improvements given their diminishing long-term outlook. As a result, coal plants have been retired, or repowered to burn gas, at an unprecedented rate over the last decade. Today, even larger, younger coal plants are struggling to survive the economic competition from cleaner, cheaper energy sources.[9]

Q. Has the wave of coal plant retirements you describe reached Duke Energy and the Carolinas?

A. Yes. According to its 2018 IRP, as of April 2015, DEC has retired approximately 1,700 MW of older coal generation.[10] Likewise, Duke Energy Progress (DEP) has retired about 1,700 MW of older coal units since 2011 and expects to retire its two Asheville coal units later this year.[11] As noted above DEC is required under a court order to retire Allen Units 1-3 in December 2024.

Q. Is there evidence that DEC's coal units are experiencing more challenging economic conditions?

A. Yes. Most of DEC's coal plants have been operating at very low and decreasing capacity factors for the past several years.

Q. What is the meaning of the term "capacity factor," as applied to electric generating units?

A. The capacity factor is the total generation produced by a unit over a certain period of time,

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[9] See, for example, E&E News, April 27, 2017: "Big Young Power Plants are Closing. Is it a new trend?" Available at https://www.eenews.net/stories/1060053677.

[10] DEC, South Carolina Integrated Resource Plan (2018) 73, *available at* http://www.energy.sc.gov/files/2018%20DEC%20Annual%20Plan_SC__Final.pdf.

[11] Duke Energy Progress, South Carolina Integrated Resource Plan (2018) 71, *available at*. http://www.energy.sc.gov/files/DEP%202018%20IRP.pdf.

often a month or a year, as a percentage of the generation it could have produced were it running at 100% of its capacity for the same period of time.

Q. What are typical capacity factors for coal plants in the United States?

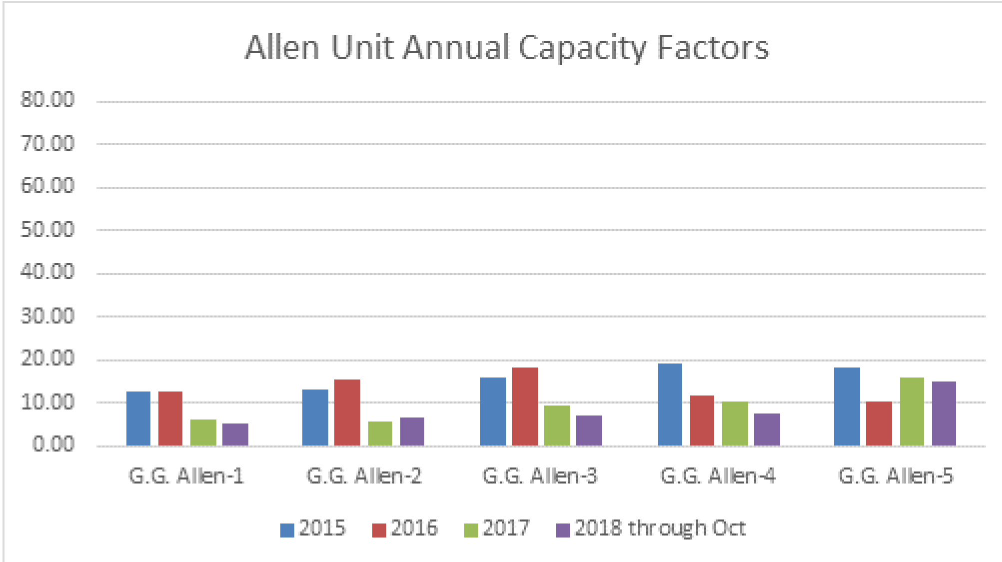
A. There is a great deal of variation depending on the plant type, efficiency, local system needs, and other factors. However, coal plants like those in DEC's fleet are designed to serve as baseload plants, which means they typically would have capacity factors of 60% to 80%, or sometimes higher.

Q. At what capacity factors have DEC's coal plants been operating under current market conditions?

A. As shown in Figure 1, all five units at Allen Station have had extremely low capacity factors for the past several years, and Units 1 through 4 have operated at capacity factors of between 5% and 10% for the last two years. Cliffside Unit 5 (Figure 2), and Marshall Units 1 and 2 (Figure 3) have also been operating at much lower capacity factors than they were around the time of the prior depreciation studies (2008 and 2011). This trend reflects their increased difficulty competing with other generation sources, and represents another reason why their long-term economic outlook is relatively poor.

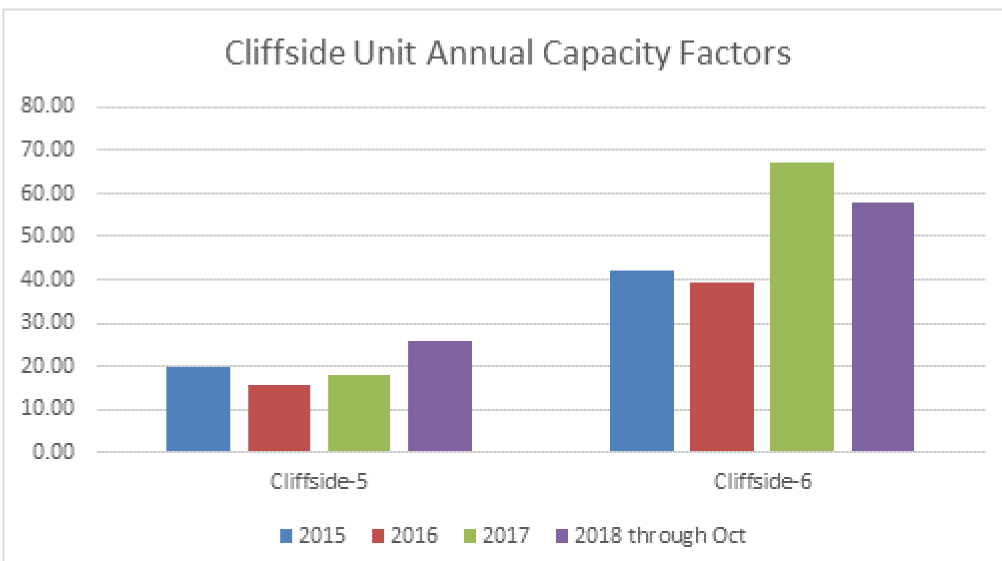
These capacity factors are not at all typical of baseload plants; in the case of the Allen units, they are closer to what would be described as peaking unit capacity factors.

Figure 1. Capacity Factors at Allen Station



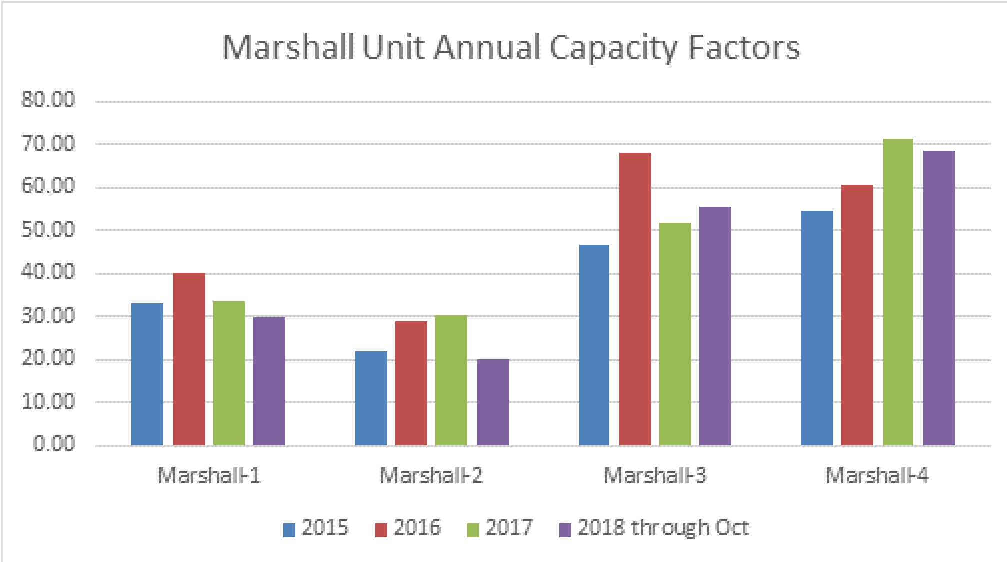
Source: S&P Global Market Intelligence; SNL Energy Data; accessed February 11, 2019.

Figure 2. Capacity Factors at Cliffside



Source: S&P Global Market Intelligence; SNL Energy Data; accessed February 11, 2019.

Figure 3. Capacity Factors at Marshall Station



Source: S&P Global Market Intelligence; SNL Energy Data; accessed February 11, 2019.

Q. Why is the capacity factor relevant to the economic performance of the units?

A. Most of the value of baseload plants lies in the energy they produce. These plants are very expensive to build and maintain, and this investment can only pay off for ratepayers if they produce as much energy as possible—i.e., if they have high capacity factors. As the output of the unit decreases, it becomes harder and harder to justify any additional expenditures to keep the plants operational and in compliance with all requirements. In this sense, low capacity factors are both a *symptom* of poor economics (because the plants can't compete with lower-cost resources) and a *cause* of diminishing economic viability.

Q. Have you found any indication that DEC no longer expects its coal resources to have high capacity factors?

A. Yes. First, Duke has described its Allen units as "peaking" units since its 2016 IRP; Cliffside Unit 5 jumped from "base" to "peaking" in DEC's 2016 IRP (Unit 6 changed from “base” to “intermediate”) and Marshall Units 1 and 2 have been considered “intermediate” at least since Duke’s 2013 IRP.[12]

In addition, information provided in response to Sierra Club data requests suggests that the Company expects the output of its coal plants to [CONFIDENTIAL] [redacted] [CONFIDENTIAL] Specifically, in response to Sierra Club data request 1-13 (attached as Exhibit 13), DEC provided the anticipated volume of bottom and fly ash it expects to produce at each of its coal units from 2018 through 2040. (It is not clear if the 2018 data are “actual” or “projected”.) Because ash production is directly related to coal combustion, this serves as strong evidence of DEC’s expectations for coal combustion at each unit during this period. As may be seen in Figure 4 through Figure 7, [CONFIDENTIAL] [redacted] [CONFIDENTIAL]

[12] DEC IRPs from 2010 through 2018 are available at http://www.energy.sc.gov/utilities.

[CONFIDENTIAL] *Figure 4. Projected fly ash production at Allen*

[redacted]

[CONFIDENTIAL] *Figure 5. Projected fly ash production at Belews Creek*

[redacted]

[CONFIDENTIAL] *Figure 6. Projected fly ash production at Cliffside*

[redacted]

[CONFIDENTIAL] *Figure 7. Projected fly ash production at Marshall Station*

[redacted]

IV. RECOMMENDATIONS

Q. What are your recommendations for the Commission in this proceeding?

A. I recommend that the Commission require DEC to complete a comprehensive economic and retirement analysis of each of its coal units. This analysis should identify and quantify the total costs of managing past and future coal combustion residuals as well as the costs of all future capital investments necessary to continue operating the plants, including additional investments to manage coal ash and other environmental compliance requirements. This comprehensive analysis should include full consideration of non-fossil-generation alternatives for meeting customer requirements, including transmission enhancements, renewable energy sources, energy efficiency, and storage. If the Commission otherwise concludes that DEC's request for recovery of coal ash remediation and cleanup costs in this proceeding are reasonable and prudent, the Commission should condition its approval on the Company's filing this comprehensive analysis for Commission review. This will allow the Commission to consider whether DEC's coal ash remediation investments provide commensurate benefits to ratepayers in the full context of the past and future operations of DEC's coal units.

Further, once the costs, benefits, and customer risks associated with continued operation of the plants versus all viable alternatives are fully evaluated, the Commission will be better positioned to assess the reasonableness and prudence of any proposed additional capital investments. Such a comprehensive evaluation will also allow the Company to better plan for transitioning to a cleaner energy mix, while minimizing the impact on ratepayers.

Q. Does this conclude your direct testimony?

A. Yes.